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Dear Sir or Madam

Ref : Call for Input on the review of locational marginal pricing

Thank you for the opportunity to respond to Ofgem's call for input on the review of locational marginal pricing. Please find below E.ON's response.

**Summary**

E.ON welcomes this very timely review of how GB buys and sells electricity and specifically the impact on the costs of where electricity is generated and consumed. Currently, wholesale electricity is bought and sold without regard to any constraints in transmission such that a supplier can buy wholesale power from a generator in the north of Scotland for consumption in London at the same price as from a generator located in Kent. Whilst network charges (TNUoS and BSUoS) look to capture the cost of any transmission constraints, these signals are currently too weak and opaque for stakeholders to factor them into investment and operational decisions. The lack of any significant locational drivers means that we are not dispatching plant to minimise cost and building new generation, demand and transmission in suboptimal areas (from the perspective of minimising electricity costs). Therefore E.ON is fully committed to ensuring that the locational element of cost is better captured in customer bills to ensure that the transition to a zero carbon electricity system in 2035 is achieved at the lowest possible cost.

However, we do not believe that there has been sufficient analysis to determine the best methodology for incorporating more cost reflective locational signals into customers' bills. Whilst locational marginal pricing (LMP) has many advantages (and is being successfully run in numerous other countries), it will also influence and affect more than just the parts of the system that it is targeted at, namely dispatch and siting decisions. Incorporating locational signals into the wholesale price will also impact upon support mechanisms for new generation that are essential to the drive towards Net Zero and a carbon free electricity system by 2035. LMP will also affect investor confidence, potentially delaying new build decisions and it could also affect customers' attitudes to equity and fairness if customers are exposed to more granular locational signals than at present. Liquidity has a significant impact on market efficiency. Deep liquid markets are essential for securing efficient prices for customers. We have not seen robust evidence that demonstrates that liquidity will

not reduce under LMP (due to having more markets with fewer generators in them). This is an area which needs to be explored in far more depth before any final decisions should be taken. Another 'difficult to quantify' impact includes disruption to the system whilst the new methodology is bedding down, and therefore serious consideration needs to be given around what form of transitional arrangements to an enduring scheme would look like. All these risks need to be weighed up against the benefits of clearer dispatch and siting information than today's methodology. However, these costs and benefits should not just be compared with the status quo, but against other options that have the potential to deliver similar locational signals.

E.ON recognises the good work that has already been contributed by National Grid ESO (NGESO) to this question as part of their Net Zero Market Review. However, as stated above, we would urge Ofgem to consider a different counterfactual to the one that NGESO used (the status quo). If all stakeholders agree that the current system is lacking necessary cost reflective locational price signals, then the counterfactual that LMP should be compared against is not the status quo, but a national wholesale price with more cost reflective network charging signals. Ofgem are currently establishing a TNUoS taskforce[1] to investigate possible reform to TNUoS and the DUoS SCR[2] is also looking at more cost reflective pricing signals for DUoS. The counterfactual to LMP ought therefore to be a national wholesale price coupled with strong and transparent TNUoS, BSUoS and DUoS forward looking pricing signals with the residual element of any network charging being the much smaller component of the overall charge. By comparing LMP to this counterfactual, Ofgem will be able to ascertain what additional benefits and risks customers will be exposed to by moving to locational signals embedded within the wholesale price.

**Questions:**

**Question 1: What are the key opportunities associated with introducing more granular locational pricing in GB?**

In summary we believe that there are several opportunities that more granular locational pricing though the wholesale market may offer to customers, but it will be essential that these are tested and challenged through thorough analysis that considers the wider impact across the system (including the distributional impact across all customer types) and against equivalent alternatives.

In summary, we believe these opportunities can be categorised as:

i. Reduced average costs through more efficient dispatch,
ii. Better decision-making (from a system perspective) regarding the siting of new generation/demand/transmission,
iii. Stronger and more transparent signals to demand (should policy makers decide to expose demand to locational signals) incentivising on-site generation/storage/demand side response (DSR),

[1] https://www.ofgem.gov.uk/publications/tnuos-task-forces
[2] https://www.ofgem.gov.uk/publications/distribution-use-system-charges-significant-code-review-launch

iv. Reduce misleading signals for interconnectors and storage, leading to more cost-effective trading with Europe.

Of these four opportunities, we believe that the key opportunity is that of lowering average costs for customers. However, we would like to clarify two caveats to this opportunity. Firstly, we believe that it is essential for this review to investigate (and which is in the scope of work as defined in the webinar material[3]) the level to which demand should be exposed to locational pricing. Secondly, we are concerned that there is an implicit assumption that all customers' costs will reduce under nodal pricing. Our early modelling suggests that there may be periods of time where some nodal prices will be higher than a national price. Therefore, we urge Ofgem to consider how these periods might affect various types of customers and how often these periods may occur.

On the question of whether demand is fully exposed to nodal prices, then under full nodal pricing for demand, customers will see the true cost impact of their location on the network, leading to customers seeing significantly different prices (analysis by Aurora suggest that a 3-node model could see average bill reduction differentials of ~£200 pa[4] between Scottish and English customers using the same amount of electricity compared to a maximum differential of ~£75 pa today[5]. Also, analysis by Energy System Catapult using a 7 node system suggests an average bill reduction differential of ~£350 pa between Scotland and Southern England[6]). This 'postcode lottery' for electricity bills would need to be managed and communicated very carefully to ensure that customers understand the reasons for these differences. This raises some very clear political risks to exposing customers to nodal prices that would need to be balanced against the efficiency improvements of full nodal pricing for all. It is not clear to us that those customers who see a £35 pa reduction in their electricity bill will see the equity of similar customers in different regions of the country seeing a £385 pa reduction to their electricity bill[7].

However, if customers are not exposed to the nodal wholesale prices for their area and rather see an averaged zonal or national price (which is common in other jurisdictions that use LMP), then suppliers (who would be exposed due to purchasing power in the full nodal wholesale market whilst selling at zonal average prices) will face significant risk from potentially having a different customer distribution across the country (and therefore a different cost base) to the zonal or national average. For example, if the nodal cost for a Scottish customer was £1000

[3] One of the sensitives to be investigated is defined as "*Vary the extent of locational price exposure to demand and to generation / storage / interconnectors……e.g. load to face national price for a period of time (at the cost of efficiency loss)*"

[4] https://policyexchange.org.uk/wp-content/uploads/Appendix-1-Aurora-Energy-Research.pdf

[5] Using the default tariff for Apr 22 – Sept 22 for single rate customers paying by standard credit and using 3100kWh pa. The maximum cost £1161.37 (inc VAT) for the North Wales and Merseyside region and the minimum cost is £1085.05 (inc VAT) for the Northern region

[6] https://es.catapult.org.uk/report/location-location-location-reforming-wholesale-electricity-markets-to-meet-net-zero/

[7] Figures taken from the Energy System Catapult report cited above

pa and  for an English customer was £1350 pa, we might expect a national cost to be ~£1315 pa (based on Scotland constituting ~10% of the population). For a Scottish dominated supplier (with a total customer base of 2.6m customers of which 27% are Scottish customers and 73% are English customers) this would mean a differential between paying the nodal price and receiving national cost from customers of ~£155m pa i.e. the Scottish dominated supplier would receive £155m pa more than they paid out. Conversely, an English dominated supplier (with a total customer base of 4.8m of which 4% are Scottish customers and 96% are English customers) would pay out £101m pa more than they receive from customers. It is not clear to us how this risk can be managed by suppliers without introducing a major new market distortion where Scottish dominated suppliers can use their cheaper Scottish customer base to offer lower prices to English customers to attract them away from English dominated suppliers.

As highlighted above, it is our belief that on average customers will see lower prices under LMP with Scottish customers seeing the largest reductions. However, our modelling suggests that under certain circumstances, southern England could see periods where the nodal price exceeds an equivalent national price (see Figure 1). This would occur when Scottish wind output is high, but overall demand is relatively low, and the England-Scotland transmission is constrained. Under these circumstances, a national wholesale market sees a low-cost plant (like nuclear) at the margin (before re-dispatch), but a southern nodal wholesale market sees a high-cost plant (like CCGT) at the margin. The cost of re-dispatching the national market to tackle the transmission constraint (e.g., pulling back Scottish nuclear and bringing on southern CCGTs) does not increase costs significantly and a situation where southern customers are paying more than they would have previously is reached. It is our suspicion that overall, these situations will not dominate, but will not be rare either. Therefore, we believe that Ofgem should not just look at what happens on average but take special care to consider situations where LMP could increase costs for some customers.

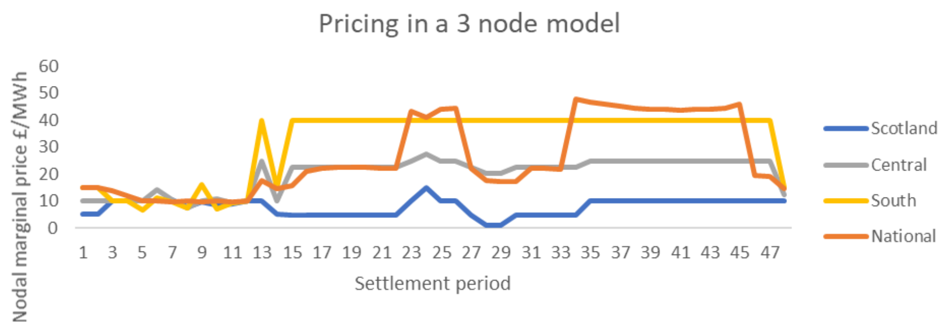


Figure 1 - National and LMP pricing from a 3-node model for a summer day (Source: E.ON analysis)

Regarding the opportunity for LMP to deliver better siting decisions for new generation, demand, and transmission, we believe that planning will be more of a driver to where new generation and transmission is sited. Without major reform of the planning system, electricity prices are liable to be a second order effect to these decisions. However, if the planning system is reformed to facilitate Net Zero investment, then LMP will become more of a significant consideration for investors.

However, a significant quantity of new generation (such as nuclear, CCUS and hydrogen) is likely to be highly constrained in where it can site. For example, the government have currently only considered two sites for CCUS and new nuclear is likely to only receive planning permission to build on existing sites. New offshore wind is also constrained to only build in areas which the Crown Estate has made available. That is not to say that LMP could not be used to inform the Crown Estate which areas are more beneficial to the system and therefore offer these in auctions, but it is not clear to us that LMP is needed to ensure that that decision is made. Therefore, it is our belief that the benefit of LMP better informing siting decisions is likely to be constrained by planning or can be captured through other, simpler mechanisms.

As we have already discussed, exposing customers to the full nodal price of wholesale power is an open question with risks and benefits that need to be carefully investigated. However, we believe that customers will play a greater part in the balancing of the system under Net Zero as more and more flexible demand and storage is built (or bought) by customers. Electric vehicles are likely to be the first asset that customers can use to participate in the energy market. As such, stronger locational signals will incentivise customers to be more flexible with their demand and possibly look to participate in V2X services (where electricity stored in the vehicle is exported to the house, the neighbourhood or back onto the grid for a price relating to the value of electricity at the time). Stronger locational signals will support customers purchasing (and using) the right types of low carbon technology e.g., thermal storage alongside heat pumps, batteries alongside PV etc. Alongside strong local flexibility markets (which will address distribution network constraints), strong transmission locational signals should help the business case for all these essential low carbon technologies that many stakeholders (such as NGESO through the Future Energy Scenarios[8] and the Committee for Climate Change through the Sixth Carbon Budget[9] etc) see as being vital to our delivery of Net Zero.

Finally, one other key benefit of LMP is the removal of misleading price signals to other, interconnected countries (such as France and Norway). With all European countries looking to deliver climate change reform equivalent to Net Zero, many focusing on similar technologies to the UK (intermittent renewables), interconnection is going to be a vital tool in tackling the problems of intermittency. Some future scenarios[10] see the UK increasing its interconnector capacity to the rest of Europe to 27GW by 2035 (from 8GW today). However, with a national price for electricity, but limited transmission capacity, NGESO have identified situations where Norway (with a lower wholesale price) might export power into Scotland and France (with a higher wholesale price) might import power from southern England, exacerbating the re-dispatch issues that we currently see today. Moving to LMP would reduce these issues by lowering the price of power in Scotland when the transmission to England is constrained and raising it in southern England, thereby reducing the spreads between the various countries. The same argument can be used for making best use of storage within the UK as well.

[8] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021
[9] https://www.theccc.org.uk/publication/sixth-carbon-budget/
[10] NGESO FES Leading the Way

**Question 2: What are the key implementation challenges, risks and mitigations?**

We have considered many of the challenges associated with LMP in Question 1, but to summarise, we believe that there are issues around LMP that need to be managed should LMP be chosen as Ofgem's preferred option. These are:

i. Liquidity
ii. Simpler options that deliver the same outcome
iii. Customer perception of locational pricing
iv. Impact on investor confidence
v. Hiatus in investment

E.ON's principal concern regarding LMP is around liquidity. With smaller (but more numerous) markets under LMP, the likelihood of a single generator holding market power in a specific node is much higher. We are not convinced by some commentators who point to the lack of liquidity in the Balancing Market when there is a constraint to be managed (i.e., only generation or demand behind the constraint can be used to alleviate it) as this lack of liquidity will only impact the imbalance price and not the wholesale price which makes up a far greater component of the overall bill. Under LMP, a lack of liquidity in a single node could drive the major part of a customer's bill to very high levels. We appreciate that other jurisdictions that operate LMP do have market power mitigation measures to prevent this happening, but these appear to be arbitrary and have to simulate competition in order to generate a bid cap which would appear to us to be a suboptimal solution.

As stated in our response to Question 1, we would like to see Ofgem seriously consider alternatives to LMP that still deliver a strong locational price signal for generators especially (and possibly customers) whilst retaining the national single price for wholesale electricity (which will maximise liquidity). It is our opinion that the recent network charging reform announcements (such as the TNUoS taskforce and the DUoS SCR) are ideal opportunities to look again at how locational signals can be made stronger and more cost reflective. This would have the additional benefit of shifting more of the network charge into cost reflective behaviour and location and less into fixed charges (delivered through the TCR) which is stifling demand side response and low carbon technology uptake.

Again, as covered in Question 1, E.ON has some very real concerns around the perceived fairness of LMP, both on customers and existing generators who have made a location decision based on a different set of rules. Exposing customers to locational pricing does have benefits and costs and these need to be analysed carefully to fully understand any impact on customer behaviour. We are especially concerned should Ofgem not consider the distributional impact of LMP across the different archetypes of customer. We also have performed some early-stage modelling of LMP which suggests that whilst customers might see lower costs on average, there will be occasions (and we have yet to fully understand how often these may occur) when the nodal price for the south of England can be significantly higher than a national price would have been (Figure 1). We will continue to investigate the circumstances of these prices and will happily share our findings with Ofgem.

E.ON does have a small portfolio of generation assets and sells generation assets to customers (such as CHPs). All of the assets that we own or operate can be aggregated together in order to participate in the current wholesale market. Therefore, we are interested in the impact that LMP might have on the commercial case for new distributed generation (DG) that is also looking to participate in the wholesale market. One obvious issue that LMP will introduce will be the difficulty in aggregating up smaller assets, especially if there are hundreds or thousands of nodes. It is not clear to us how DG will be able to compete on a level playing field against transmission connected generation with some DG assets sitting behind constraints and some sitting in front of constraints. If participation in the wholesale market remains limited to assets (or aggregated assets) of >1MW this is likely to distort the market against DG.

We anticipate that many generators will be able to provide more comprehensive input to Ofgem about the impact that LMP will have on investor confidence and hence cost of capital. We note the findings from the NGESO review that suggests that in other jurisdictions cost of capital does not appear to have been adversely impacted by the introduction of LMP. However, in the UK, new generation has benefitted from very high investor confidence (through support from the CfD mechanism) and will undoubtedly see more risk applied to their projects, especially at the end of any support payments they may have received. This raises the question about LMP's impact on merchant investment especially.

E.ON has significant concerns regarding the level of supported generation and the lack of new merchant plant due to its impact on wholesale liquidity. With CfD supported generation completely unexposed to the wholesale market, there is no incentive (and in fact there are disincentives) for this generation to adapt its output to support system security i.e., turn off when a constraint is met. CfD supported generation is incentivised to sell its output close to real time in order to minimise its imbalance risk (as the price risk has been completely removed). This is having an adverse impact on liquidity further along the forward curve e.g. S+1, Q+2 etc. Lower liquidity brings more volatility into the market which will only serve to drive prices up for suppliers who will look to mitigate this risk through risk premiums. We would welcome changes alongside any strengthening of locational signals to include adaptations to the CfD mechanism that incentivises generation to be more exposed to the wholesale market and sell its output further out.

Finally, any major change to the wholesale market has the potential to lead to a brief reduction in investment as stakeholders learn and adapt their strategies to the new rules. Ofgem should consider what appropriate transitional arrangements could reduce this risk alongside investigating other options that could deliver similar outcomes (such as retaining a national price but adapting network charges to make them more locational).

**Question 3: Do you agree with the proposed approach to modelling zonal and nodal market designs?**

Based on the workshop material and discussion, we are broadly in agreement with the modelling approach that Ofgem is following e.g. the number of zones/nodes considered, the different scenarios used for future new build of transmission, generation and demand etc. We stress again that Ofgem need to consider the impacts of LMP across many different types of customers and that the average demand should not be the only output considered.

We reiterate that Ofgem need to consider whether using the status quo as the counterfactual to compare against LMP is the right method to use. It is our view (and there appears to be broad agreement across the industry) that the status quo does not deliver the locational signals that are essential to realise the whole system benefits under Net Zero and that using the status quo as the counterfactual will show the benefit of locational signals without considering the scenario of a national price coupled with strong locational signals through reformed network charges.